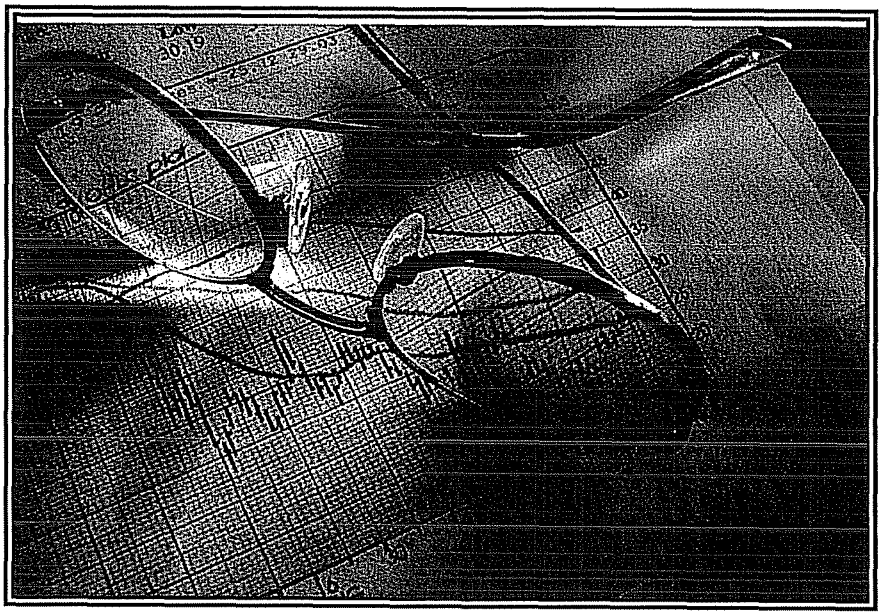
Louisville Gas & Electric Company
Kentucky Utilities Company
Marginal Cost of Service Study

August 2011



Prepared by:

■ The Prime Group ■

Priority Cost of Service, Rate and Regulatory Support

6001 Claymont Village Drive, Suite 8
Crestwood, KY 40014

Table of Contents

Executive Summary 2
Introduction 4
Marginal Cost Theory 5
Marginal Production Demand Cost 6
Marginal Production Energy Cost 10
Marginal Transmission Cost 10
Marginal Distribution Cost 12
Summary 12
Attachments 13

Executive Summary

Louisville Gas & Electric Company ("LG&E) and Kentucky Utilities Company ("KU") (collectively "LG&E/KU" or "the Companies") retained The Prime Group, LLC to prepare an estimate of the Companies' marginal cost of providing electric service.

Marginal cost is defined as the change in total cost with respect to a small change in demand (or "output"). In this study, output refers to the total megawatts of capacity or megawatt hours of energy, so that marginal cost is the change in total system cost relative to a small change in total system capacity or energy.

This report describes the methods for estimating marginal production, transmission, and distribution costs for LG&E/KU. For production, the fixed marginal cost and the variable marginal cost are evaluated independently. Results are tabulated herein and in Table ES-1.

Table ES-1.
Louisville Gas & Electric Company and Kentucky Utilities Company
Summary of Marginal Cost of Service

Function	**Marginal Cost of Service**	
	LG&E	**KU**
Production Demand (per KW of Added NCP Demand)	$2.49	$2.49
Production Energy (per KWH of Added Energy)	$0.02608	$0.02608
Transmission (per KW of Added NCP Demand)	$0.43	$0.43

Marginal production demand cost and its calculation is best looked at from the perspective of the electrical system utility planner. The planner begins by developing a schedule of resource acquisitions which allows the utility to meet its forecasted demand obligations. The planner then must address how any incremental demand will be met. Perhaps most often, anticipated additional demand is met by taking the existing plan for generation expansion and accelerating it. Using the production cost model and the information filed in the Companies' 2011 Integrated Resource Plan, the marginal production demand costs are associated with advancing a combined cycle combustion turbine from 2018 to 2017 in-service. The calculation of an Economic Carrying Charge is used to determine the costs of advancing this capital asset by one year.

Marginal production energy costs are derived from the combined-Company variable costs for the twelve months ended July, 2011.

Marginal transmission costs are determined using a similar approach to the production demand. The plant additions are derived from FERC Form 1 data from 1991 to 2010 and are used with the application of an Economic Carrying Charge Rate to determine the marginal transmission cost for LG&E and KU.

Marginal distribution costs are not calculated because the responsibility for such costs are governed by the Line Extension Plan established by KU and LG&E and approved by the Commission in Case Nos. 2009-00548 and 2009-00549 respectively.

This analysis may be utilized to support the commitment made by the Companies in a recent proceeding, *In The Matter Of: Application Of Louisville Gas And Electric Company And Kentucky Utilities Company To Modify And Rename The Brownfield Development Rider As The Economic Development Rider* in Case No. 2011-00118. In its Order dated August 11, 2011, the Commission noted if the Companies offer special contracts under their Economic Development rate, the Companies will demonstrate with each special contract filing that the discounted rates exceed the marginal cost associated with serving the customer. (Order, page 7.) The marginal cost study presented herein is applicable for such a demonstration.

Introduction

Louisville Gas & Electric Company ("LG&E) and Kentucky Utilities Company ("KU") (collectively "LG&E/KU" or "the Companies") retained The Prime Group, LLC to prepare an estimate of the Companies' typical marginal costs of delivering electricity.

Marginal cost is defined as the change in total cost with respect to a small change in demand, or output. In this report "output" will be used in place of "demand" to avoid confusion with the standard way that the term "demand" is used in the industry to represent the maximum amount of power utilized during any interval over a specified period of time. Therefore, in this study, output refers to the total megawatts of capacity or megawatt hours of energy, so that marginal cost is the change in total system cost relative to a small change in total system capacity or energy.

This report describes the methods for estimating marginal production, transmission, and distribution costs for LG&E/KU. For production, the fixed marginal cost and the variable marginal cost are evaluated independently. The report includes summary tables of the results.

The marginal costs are determined using the resource planning tools that the Companies rely on for development of their Integrated Resource Plan ("IRP"), which is formally prepared every three years and which was most recently filed with the Kentucky Public Service Commission ("the Commission") on April 21, 2011, in Case No. 2011-00140. The study is also based on data from the Companies' official books and records as reflected on the Form 1 filings with the Federal Energy Regulatory Commission ("FERC"). Form 1 data utilized includes system peak demand data (in MW) and transmission and distribution cost data (in $) by FERC account. Cost escalation factors were determined using the Consumer Price Index ("CPI") data from the U.S. Department of Labor Bureau of Labor Statistics and/or the Handy-Whitman Index of Public Utility Construction Costs ("Handy-Whitman Index"), as appropriate for the particular type of cost to be escalated.

Marginal costs have several applications. In most jurisdictions in the U.S., the most common application of marginal cost studies by utilities is for designing economic development or other incentive rates. Similarly, the marginal costs are also utilized for analyzing discounted rates provided to certain customers pursuant to special contracts. Another application is for the development of particular components of other rate offerings, e.g. determining rate differentials for use in time-differentiated rates, such as time-of-use or critical-peak-pricing rate schedules.

In particular for LG&E and KU, this analysis may be utilized to support the commitment made by the Companies in a recent proceeding, *In The Matter Of: Application Of Louisville Gas And Electric Company And Kentucky Utilities Company To Modify And Rename The Brownfield Development Rider As The Economic Development Rider* in Case No. 2011-00118. In its Order dated August 11, 2011, the Commission noted if the Companies offer special contracts under their Economic Development rate, the Companies will demonstrate with each special contract filing that the discounted rates exceed the marginal cost associated with serving the customer. (Order, page 7.) The marginal cost data presented herein, or in subsequent studies, is applicable for such a demonstration.

Marginal Cost Theory

Marginal cost is defined as an infinitesimal change in total cost with respect to an infinitesimal change in output. Mathematically, marginal cost can be represented as the partial derivative of total cost to output, and can be stated as follows:

$$MC = \frac{\partial C}{\partial q}$$

where

MC = Marginal Cost
∂C = Infinitesimal change in Total Cost
∂q = Infinitesimal change in Output

In the context of discrete cost and output, marginal cost can be *estimated* as follows:

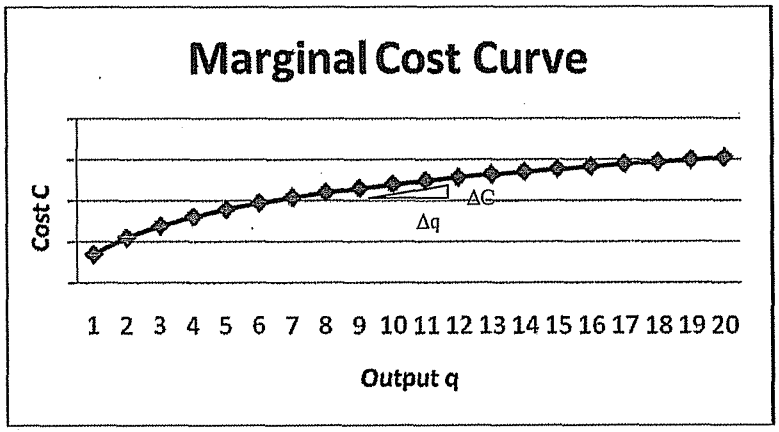
$$MC = \frac{\Delta C}{\Delta q}$$

where

MC = Marginal Cost
ΔC = Change in Total Cost
Δq = Change in Output

Graphically, the marginal cost is the slope of the line resulting from the graph of the total cost C and the total output q, as shown in Figure 1.

Figure 1. Cost vs. Output Curve



In the figure, "output" refers to total megawatts of capacity or megawatt hours of energy required, so that marginal cost is the change in total system cost relative to a small change in total system output.

Marginal Production Demand Cost

The marginal demand costs for production are the changes in capacity costs associated with serving changes in demand on the electric system.

Recall that marginal cost is broadly defined as the change in total cost with respect to a small change in output. In this instance, the "output" refers to total megawatts of generating capacity required, so that marginal cost is the change in total system capacity cost relative to a small change in total system demand.

Marginal production demand cost and its calculation is best looked at from the perspective of the electrical system utility planner. The planner begins by developing a schedule of resource acquisitions which allows the utility to meet its forecasted demand obligations. The planner then must address how any incremental demand will be met. Perhaps most often, anticipated additional demand is met by taking the existing plan for generation expansion and accelerating it.[1]

To evaluate the change in capacity costs, a base case is defined that specifies the capacity (and associated capacity cost) required to meet the Companies' base demand forecast for the planning period. Other scenarios are then developed in which the total system demand is increased by set increments, and the capacity acquisitions required to meet those incremental demands are determined. The net present value of the capacity costs in the base case is then compared to the net present value of the capacity costs for the incremental cases to determine the change in capacity cost associated with the change in total system demand.

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[1] Charles J. Cicchetti, et al, *The Marginal Cost and Pricing of Electricity: An Applied Approach* (Cambridge, MA: Ballinger Publishing Co., 1977), 8.

The base case is essentially the resource acquisition plan identified in the Companies' IRP, which was recently filed with the Commission on April 21, 2011, in Case No. 2011-00140. (Some minor revisions to the model have been incorporated since, with negligible effects.) The IRP identifies the capacity resources needed to meet the Companies' forecast load plus the target reserve margin for a fifteen-year planning horizon on a least-cost basis. The plan includes both supply-side and demand-side resources, but for this assessment only the supply-side resources are considered. The IRP is summarized in Table 1.

Thus the base case is essentially the same as the 2011 IRP, and the cases with incremental total system demand are then prepared and compared to the base case.

Another way to consider this approach is to consider a stable system (the base case). The initial condition is then perturbed (by a small increase in system demand), and equilibrium is re-established (by adjustments to the resource acquisition plan). This process is repeated for several incremental perturbations (i.e. by incremental increases to system demand in blocks of say 25 MW). The cost of the stable base case are then compared to the costs of the stable incremental cases to determine the marginal cost (at whatever increment first requires a change to the resource acquisition plan).

Incremental demands of 25 MW, 50 MW, 75 MW and 100 MW were evaluated to assess the impacts on the resource plan and the associated costs.

The timing of the generation additions needed to meet demand obligations in each year of the planning period for all of the scenarios are determined by the detailed resource planning computer model Strategist®, which the Companies routinely use in the IRP and in other generation planning and forecast evaluations. The capacity costs associated with the supply resource additions listed are included in the IRP. The primary source of the capital cost estimates from the IRP is the EPRI TAG, a report funded by the sponsors of EPRI's Program 9. This is described in the report titled *Analysis of Supply-Side Technology Alternatives* (March 2011) contained in Volume III of the 2011 IRP.

Table 1.
Recommended 2011 Integrated Resource Plan

Year	Resource
2011	38 MW DSM Initiatives
2012	58 MW DSM Initiatives
2013	59 MW DSM Initiatives
2014	68 MW DSM Initiatives
2015	61 MW DSM Initiatives
2016	61 MW DSM Initiatives **(797) MW Coal Unit Retirements at Cane Run, Green River, & Tyrone** **907 MW 3x1 Combined Cycle Combustion Turbine**
2017	61 MW DSM Initiatives
2018	58 MW DSM Initiatives **907 MW 3x1 Combined Cycle Combustion Turbine**
2019	58 MW DSM Initiatives
2020	58 MW DSM Initiatives
2021	58 MW DSM Initiatives
2022	58 MW DSM Initiatives
2023	58 MW DSM Initiatives
2024	58 MW DSM Initiatives
2025	58 MW DSM Initiatives **907 MW 3x1 Combined Cycle Combustion Turbine**

Notes:

- DSM initiatives are incremental proposed programs including one program with annual savings that do not accumulate.
- Unit ratings for new units and retirements are summer net ratings.

The cases and the impacts on the resource plan are summarized in Table 2.

Increasing the total system demand by 25 MW or by 50 MW does not require any change to the resource acquisition plan in the IRP; those resources are sufficient to meet this incremental demand and there is no incremental capacity cost relative to the IRP costs for these additions.

Table 2.
Case Summary for Marginal Cost Evaluation

Case	Incremental Demand	Change to Resource Acquisition Plan?
Base	n/a	n/a
Case 1	25 MW	No
Case 2	50 MW	No
Case 3	75 MW	Yes
Case 4	100 MW	Yes

Increasing the total system demand by 75 to 100 MW, however, requires that the resource acquisition plan in the IRP be revised in order to meet the incremental demand obligations. The acquisition of a 3x1 Combined Cycle CT must be advanced from 2018 to 2017 in order to meet the incremental 75 MW obligation. This change is highlighted in Table 3. (Other portions of the plan that do not differ, including all of the demand-side options, are not included for the sake of simplicity.)

Table 3.
Change in Resource Plan for Incremental 75 or 100 MW Demand

Year	Base Case	+75 MW Case or +100 MW Case
2016	3x1 Combined Cycle Combustion Turbine	3x1 Combined Cycle Combustion Turbine
2017		3x1 Combined Cycle Combustion Turbine
2018	3x1 Combined Cycle Combustion Turbine	

To determine the change in capacity costs associated with the advancement of the 3x1 Combined Cycle from 2018 to 2017, the *Economic Carrying Charge* is calculated. The Economic Carrying Charge is the economic cost of advancing or delaying the present value of revenue requirements associated with capital expenditures. This computation is described in Attachment A.

The marginal production demand cost is the monthly value of the Economic Carrying Charge Rate ("ECRR") applied to the present value revenue requirement ("PVRR") of the capital asset. The computation of both the PVRR of the capital asset and the Economic Carrying Charges are provided in Attachment B. Because the fixed O&M expenses were negligible in comparison to the asset costs, they were not included in the analysis.

Based on the computations included in Attachments A and B, the marginal production demand cost on a Coincident Peak ("CP") basis is $3.60 per month. Using an average coincidence factor from the last KU and LG&E rate cases, the CP marginal cost value is converted to a Non-Coincident Peak ("NCP") marginal cost value of $2.49 per month. Because the LG&E and KU generating units are jointly operated to meet the combined demands of the LG&E and KU systems, a single value is provided for the marginal production demand cost on a joint Company basis. For evaluating an economic development offer, it would be necessary to adjust the NCP marginal cost value to reflect the applicable loss-factor for a prospective customer which could take service at a transmission, primary or secondary voltage.

Marginal Production Energy Cost

The marginal production energy cost is derived from the most recent twelve months of actual average variable production cost data for the LG&E/KU system. Specifically, the Company provided data for the twelve months ended July 2011 pertaining to the total costs for fuel, consumables (including scrubber reactants and other reagents), ash and waste disposal, and emission allowances. The total generation from the corresponding twelve months was then used to calculate a total average variable cost, on an annual combined-Company basis. This computation is described in Attachment C. Because the preponderance of LG&E and KU's generating assets are base-load resources, average marginal energy costs will not differ materially from average energy costs on an annual basis.

The marginal production energy cost per KWH of additional energy is $0.02608. Again, it would be necessary to adjust the marginal energy cost value to reflect the applicable loss-factor for a prospective customer which could take service at a transmission, primary or secondary voltage.

Marginal Transmission Cost

The marginal transmission cost is calculated using the Economic Carrying Charge approach outlined above, but with different source data. The general approach of applying an ECRR to the PVRR of the capital asset is followed; however, in the case of transmission, the capital asset is not a new generating unit but instead represents the value of additional transmission plant.

Recall that marginal costs are defined as the change in total cost with respect to a small change in output. For discrete costs and output, the formula is:

$$MC = \frac{\Delta C}{\Delta q}$$

where

MC = Marginal Transmission Cost
ΔC = Change in Total Cost of Transmission Plant
Δq = Change in system demand

The plant data is derived from the Companies' Transmission Costs as reported on the FERC Form 1 filings.[2] Data from 1991 through 2010 was compiled for KU and LG&E transmission. To determine the change in plant from one year to the next -- i.e. to identify the incremental plant -- the annual change in net plant reported on the FERC Form 1 for KU and LG&E were calculated. The net change was then indexed to 2010 dollars using factors from the Handy-Whitman Index. The indexed change in transmission plant is ΔC. The data for KU and LG&E system demands in MW from 1991 through 2010 was also compiled from the FERC Form 1 filings.[3] The change in demand from one year to the next is Δq. In this way, the amount for each year-to-year increment is calculated as $\Delta C / \Delta q$. The average amount for the multi-year period is then calculated. The calculations of the additional transmission investments for KU and LG&E are shown in Attachment D.

The average transmission addition amount for KU is then input as the PVRR in the determination of the Economic Carrying Charge, as demonstrated in Attachment E. The determination of the ECRR is identical to the approach used for marginal production demand costs, where the PVRR, inflation rate, weighted average cost of capital, and other factors described in Attachment A are used to determine the cost value on a CP basis. The CP value is then converted to an NCP value using the average coincidence factor from the most recent KU and LG&E rate cases. The entire process is repeated for LG&E, as demonstrated in Attachment F. Because the fixed O&M expenses were negligible in comparison to the asset costs, they were not included in the analysis.

For KU, the marginal transmission cost per KW of additional NCP demand is $0.43. For LG&E, the marginal transmission cost per KW of additional NCP demand is also $0.43. This is purely coincidence as the values are derived separately for KU and LG&E from their respective FERC Form 1 filings. Again, it would be necessary to adjust the marginal transmission cost value to reflect the applicable loss-factor for a prospective customer which could take service at a transmission, primary or secondary voltage.

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[2] FERC Form 1, Page 206, Line No. 58.
[3] FERC Form 1, Page 410b, Column D

Marginal Distribution Cost

The marginal distribution cost for KU and LG&E in theory could be calculated using the same approach as the marginal transmission costs. However, from a ratemaking and policy standpoint, distribution and transmission differ. For distribution, the Companies established a Line Extension Plan, most recently approved on July 30, 2010 by the Commission for KU and LG&E in Case Nos. 2009-00548 and 2009-00549 respectively. The Line Extension Plan is applicable in all service territory where the Companies do not have existing facilities to meet the electric service needs of its retail customers. The plan specifies how the costs for normal line extensions and other line extensions will be handled. This practice makes moot the determination of a marginal distribution cost for the system at large because any individual facility addition, and its particular costs, will be considered on an actual-cost and specific-customer basis, pursuant to the Line Extension Plan.

Summary

The marginal costs for KU and LG&E for Production Demand, Production Energy, and Transmission are summarized in Table 4.

Table 4.
Louisville Gas & Electric Company and Kentucky Utilities Company
Summary of Marginal Cost of Service

Function	**Marginal Cost of Service**	
	LG&E	**KU**
Production Demand (per KW of Added NCP Demand)	$2.49	$2.49
Production Energy (per KWH of Added Energy)	$0.02608	$0.02608
Transmission (per KW of Added NCP Demand)	$0.43	$0.43

Attachments

Computation of the Economic Carrying Charges Associated With Delaying a Planned Generating Resource by a Fixed Number of Years

Economic carrying charges are the economic costs of advancing (moving forward) or delaying (moving backwards) the present value revenue requirements associated with a capital expenditure. In other words, an economic carrying charge is a measurement of the effect on a utility's present value revenue requirements (PVRR) of advancing or delaying the installation of a utility resource. For example, if an increase in load causes a generating resource to be moved forward *a* years, the economic carrying charges measures the effect on PVRR of moving the resource forward *m* years. Economic carrying charges are often calculated assuming a=1 (i.e., moving the resource forward one year).

Where:

ECC = Economic Carrying Charges

ECCR = Economic Carrying Charge Rate

PVRR = Present value revenue requirement for the asset in current dollars.

g = Annual Inflation Rate

r = Weighted Cost of Capital

L = Life of the asset

i = index factor representing every L years

a = the number of years that the asset is advanced

m = the number of years prior to when the asset is installed after taking into consideration the number of years *a* that the asset is advanced, necessary to reflect the carrying charge rate in current year dollars.

$$ECC = \frac{(1+g)^m}{(1+r)^m}\left[\sum_{i=0}^{\infty} PVRR\,\frac{(1+g)^{Li}}{(1+r)^{Li}} - \frac{(1+g)^a}{(1+r)^a}\sum_{i=0}^{\infty} PVRR\,\frac{(1+g)^{Li}}{(1+r)^{Li}}\right]$$

$$= \frac{(1+g)^m}{(1+r)^m}\left[PVRR\left\{\sum_{i=0}^{\infty}\frac{(1+g)^{Li}}{(1+r)^{Li}} - \frac{(1+g)^a}{(1+r)^a}\sum_{i=0}^{\infty}\frac{(1+g)^{Li}}{(1+r)^{Li}}\right\}\right]$$

$$= \frac{(1+g)^m}{(1+r)^m}\left[PVRR\left\{\left(1-\frac{(1+g)^a}{(1+r)^a}\right)\sum_{i=0}^{\infty}\frac{(1+g)^{Li}}{(1+r)^{Li}}\right\}\right]$$

$$= \frac{(1+g)^m}{(1+r)^m}\left[PVRR\left\{\left(1-\frac{(1+g)^a}{(1+r)^a}\right)\sum_{i=0}^{\infty}\left(\frac{(1+g)^{L}}{(1+r)^{L}}\right)^i\right\}\right]$$

$$= PVRR\,\frac{(1+g)^m}{(1+r)^m}\left[\left(1-\frac{(1+g)^a}{(1+r)^a}\right)\left[\frac{1}{1-\frac{(1+g)^L}{(1+r)^L}}\right]\right]$$

The last step in the above derivation converts a infinite geometric series to a fixed value. Mathematically, a geometric series converges to the following value as long as $0 \leq x \leq 1$:

$$\sum_{i=0}^{\infty} x^i = \frac{1}{1-x}$$

(See, for example, Walter Rudin, *Principles of Mathematical Analysis* (McGraw-Hill, Inc.; 1976) at 61.) In the context of an economic carrying charge, the infinite series shown in the penultimate line of the above derivation will converge to a known value as long as $g < r$.

The Economic Carrying Charges (ECC) can also be calculated by multiplying the PVRR by an Economic Carrying Charge Rate (ECCR) (i.e. ECC = PVRR x ECCR), where the ECCR is calculated as follows:

$$ECCR = \frac{(1+g)^m}{(1+r)^m}\left[\left(1-\frac{(1+g)^a}{(1+r)^a}\right)\left[\frac{1}{1-\frac{(1+g)^L}{(1+r)^L}}\right]\right]$$

Louisville Gas & Electric and Kentucky Utilities
Economic Carrying Charge of New Combined Cycle CT Addition

Assumptions	Values
Inflation Rate (g)	2.50%
Weighted Cost of Capital (r)	7.41%
Year Scheduled to be Installed	2018
Year Installed After Load Addition	2017
a	1
Current Year	2011
m	6
PVRR	1058.05
Service Life (L)	40
Economic Carrying Charge Rate (ECRR)	4.08%
Coincidence Factor	69.19%

Annual Value (CP) =	$	**43.17**
Annual Value (NCP) =	$	**29.87**
Monthly Value (CP) =	$	**3.60**
Monthly Value (NCP) =	$	**2.49**

$$ECCR = \frac{(1+g)^m}{(1+r)^m}\left[\left(1-\frac{(1+g)^a}{(1+r)^a}\right)\left[\frac{1}{1-\frac{(1+g)^L}{(1+r)^L}}\right]\right]$$

Louisville Gas & Electric and Kentucky Utilities
Present Value Revenue Requirement Analysis
New Combined Cycle CT Addition

Assumptions:

Investment	$	869
Book Life		*40*
Tax Life		20
Composite Tax Rate		38.9000%
Property Tax Rate		*0.55%*
Levelized Revenue Requirement Years		40

Results:

Present Value Revenue Requirement	$	1,058
Levelized Revenue Requirement	$	83
Levelized Carrying Charge Rate		9.57%

Year	**Investment**	**Book Depreciation**	**Net Plant**	**Tax Depreciation**	**Residual Plant**	**Deferred Income Tax**	**Accumulated Deferred Income Tax**
0	$ 869						
1		$ 22	$ 847	$ 33	$ 836	$ 4	$ 4
2		22	826	63	774	16	20
3		22	804	58	716	14	34
4		22	782	54	662	12	47
5		22	760	50	612	11	58
6		22	739	46	566	9	67
7		22	717	42	524	8	75
8		22	695	39	485	7	82
9		22	673	39	446	7	89
10		22	652	39	407	7	95
11		22	630	39	368	7	102
12		22	608	39	330	7	108
13		22	587	39	291	7	115
14		22	565	39	252	7	122
15		22	543	39	213	7	128
16		22	521	39	174	7	135
17		22	500	39	136	7	142
18		22	478	39	97	7	148
19		22	456	39	58	7	155
20		22	435	39	19	7	161
21		22	413	19	(0)	(1)	161
22		22	391	-	(0)	(8)	152
23		22	369	-	(0)	(8)	144
24		22	348	-	(0)	(8)	135
25		22	326	-	(0)	(8)	127
26		22	304	-	(0)	(8)	118
27		22	282	-	(0)	(8)	110
28		22	261	-	(0)	(8)	101
29		22	239	-	(0)	(8)	93
30		22	217	-	(0)	(8)	85
31		22	196	-	(0)	(8)	76
32		22	174	-	(0)	(8)	68
33		22	152	-	(0)	(8)	59
34		22	130	-	(0)	(8)	51
35		22	109	-	(0)	(8)	42
36		22	87	-	(0)	(8)	34
37		22	65	-	(0)	(8)	25
38		22	43	-	(0)	(8)	17
39		22	22	-	(0)	(8)	8
40		22	(0)	-	(0)	(8)	(0)

Louisville Gas & Electric and Kentucky Utilities
Present Value Revenue Requirement Analysis
New Combined Cycle CT Addition

Assumptions:

Investment	$ 869
Book Life	40
Tax Life	20
Composite Tax Rate	38.9000%
Property Tax Rate	0.55%
Levelized Revenue Requirement Years	40

Results:

Present Value Revenue Requirement	$ 1,058
Levelized Revenue Requirement	$ 83
Levelized Carrying Charge Rate	9.57%

Year	Rate Base	Interest	Equity	Property Taxes	Income Taxes	Annual Rev Requirement	Present Value Interest Factor	Present Value Revenue Requirement
0							1.000000	$ -
1	$ 843	$ 15	$ 47	$ 5	$ 30	$ 119	0.931012	111
2	805	14	45	5	29	115	0.866783	99
3	770	14	43	4	28	111	0.806986	89
4	735	13	41	4	26	107	0.751313	80
5	703	13	39	4	25	103	0.699482	72
6	672	12	38	4	24	100	0.651226	65
7	642	12	36	4	23	96	0.606299	58
8	613	11	34	4	22	93	0.564472	52
9	585	10	33	4	21	90	0.525530	47
10	557	10	31	4	20	86	0.489275	42
11	528	9	30	3	19	83	0.455521	38
12	500	9	28	3	18	80	0.424095	34
13	472	8	26	3	17	77	0.394838	30
14	443	8	25	3	16	74	0.367599	27
15	415	7	23	3	15	70	0.342239	24
16	386	7	22	3	14	67	0.318628	21
17	358	6	20	3	13	64	0.296647	19
18	330	6	19	3	12	61	0.276182	17
19	301	5	17	3	11	57	0.257129	15
20	273	5	15	2	10	54	0.239390	13
21	252	5	14	2	9	52	0.222875	12
22	239	4	13	2	9	50	0.207499	10
23	226	4	13	2	8	49	0.193184	9
24	212	4	12	2	8	47	0.179857	8
25	199	4	11	2	7	45	0.167449	8
26	186	3	10	2	7	44	0.155897	7
27	173	3	10	2	6	42	0.145142	6
28	159	3	9	1	6	41	0.135129	5
29	146	3	8	1	5	39	0.125807	5
30	133	2	7	1	5	38	0.117127	4
31	196	4	11	1	7	44	0.109047	5
32	174	3	10	1	6	42	0.101524	4
33	152	3	9	1	5	39	0.094520	4
34	130	2	7	1	5	37	0.087999	3
35	109	2	6	1	4	34	0.081928	3
36	87	2	5	0	3	32	0.076276	2
37	65	1	4	0	2	29	0.071014	2
38	43	1	2	0	2	27	0.066115	2
39	22	0	1	0	1	24	0.061554	1
40	(0)	(0)	(0)	(0)	(0)	22	0.057307	1
Net Present Value Revenue Requirement								$ 1,058

Louisville Gas & Electric and Kentucky Utilities
Present Value Revenue Requirement Analysis
New Combined Cycle CT Addition

Assumptions:	
Investment	$ 869
Book Life	40
Tax Life	20
Composite Tax Rate	38.9000%
Property Tax Rate	0.55%
Levelized Revenue Requirement Years	40

Results:	
Present Value Revenue Requirement	$ 1,058
Levelized Revenue Requirement	$ 83
Levelized Carrying Charge Rate	9.57%

Year	**Cumulative Present Value Revenue Requirement**	**Annual Carrying Charge Rate**
0	$ -	
1	111	13.70%
2	210	13.21%
3	300	12.74%
4	380	12.29%
5	452	11.87%
6	517	11.46%
7	575	11.07%
8	628	10.70%
9	675	10.32%
10	717	9.95%
11	755	9.58%
12	789	9.21%
13	819	8.83%
14	846	8.46%
15	870	8.09%
16	892	7.72%
17	911	7.34%
18	927	6.97%
19	942	6.60%
20	955	6.23%
21	967	5.95%
22	977	5.77%
23	986	5.59%
24	995	5.41%
25	1,002	5.22%
26	1,009	5.04%
27	1,015	4.86%
28	1,021	4.68%
29	1,026	4.50%
30	1,030	4.32%
31	1,035	5.10%
32	1,039	4.81%
33	1,043	4.52%
34	1,046	4.23%
35	1,049	3.94%
36	1,051	3.65%
37	1,054	3.37%
38	1,055	3.08%
39	1,057	2.79%
40	1,058	2.50%

Louisville Gas & Electric and Kentucky Utilities
Weighted Cost of Capital and MACRS

Capital Structure:

	Percent	Rate	Weighted COC	Tax Rate	Adjusted Rate
Debt	46.52%	3.86%	1.79%	38.90%	1.10%
Preferred Equity	0.00%	0.00%	0.00%		0.00%
Common Equity	53.48%	10.50%	5.62%		5.62%
			7.41%		6.71%

Tax Depreciation Table (MACRS)

	5		15	20
1	20.000%	10.000%	5.000%	3.750%
2	32.000%	18.000%	9.500%	7.219%
3	19.200%	14.400%	8.550%	6.677%
4	11.520%	11.520%	7.700%	6.177%
5	11.520%	9.220%	6.930%	5.713%
6	0.000%	7.370%	6.230%	5.285%
7	0.000%	6.550%	5.900%	4.888%
8	0.000%	6.550%	5.900%	4.522%
9	0.000%	6.560%	5.910%	4.462%
10	0.000%	6.550%	5.900%	4.461%
11	0.000%	0.000%	5.910%	4.462%
12	0.000%	0.000%	5.900%	4.461%
13	0.000%	0.000%	5.910%	4.462%
14	0.000%	0.000%	5.900%	4.461%
15	0.000%	0.000%	5.910%	4.462%
16	0.000%	0.000%	2.950%	4.461%
17	0.000%	0.000%	0.000%	4.462%
18	0.000%	0.000%	0.000%	4.461%
19	0.000%	0.000%	0.000%	4.462%
20	0.000%	0.000%	0.000%	4.461%
21	0.000%	0.000%	0.000%	2.231%
22	0.000%	0.000%	0.000%	0.000%
23	0.000%	0.000%	0.000%	0.000%
24	0.000%	0.000%	0.000%	0.000%
25	0.000%	0.000%	0.000%	0.000%
26	0.000%	0.000%	0.000%	0.000%
27	0.000%	0.000%	0.000%	0.000%
28	0.000%	0.000%	0.000%	0.000%
29	0.000%	0.000%	0.000%	0.000%
30	0.000%	0.000%	0.000%	0.000%

Kentucky Utilities and Louisville Gas and Electric Company
Marginal Energy Costs
12 Months ending July 2011

Variable Materials and Disposal		Amount
Scrubber Reactant Ex	$	23,127,067
Nox Reduction Reagent (Ammonia)	$	7,086,842
Sorbent Injection (Hydrated Lime/Trona)	$	11,747,266
Activated Carbon	$	117,120
Consumables	**$**	**42,078,295**
Other Waste Disposal	$	2,776,576
Bottom Ash Disposal	$	1,175,437
Fly Ash Disposal	$	96,638
Disposal	**$**	**4,048,650**
Emission Allowances	**$**	**198,521**

Fuel		Amount
FUEL-COAL - TON	$	832,048,008
START-UP OIL -GAL	$	5,134,206
STABILIZATION OIL - GAL	$	4,695,765
START-UP GAS - MCF	$	2,823,052
STABILIZATION GAS - MCF	$	3,966,229
FUEL-GAS - MCF	$	56,440,842
FUEL-OIL - GAL	$	1,524,740
FUEL - GAS - INTRACOMPANY	$	1,400,632
Total Fuel	**$**	**908,033,474**
Total Variable Costs	**$**	**954,358,941**

Generation	
KWH GENERATED-COAL - (STAT ONLY)	35,635,560,000
KWH GENERATED-HYDRO - (STAT ONLY)	253,802,000
KWH GEN-OTH PWR-OIL - (STAT ONLY)	6,677,000
KWH GEN-OTH PWR-GAS - (STAT ONLY)	698,941,000
Total Generation	**36,594,980,000**
Marginal Energy Cost ($/MWh)	**26.08**

Summary by Fuel Type

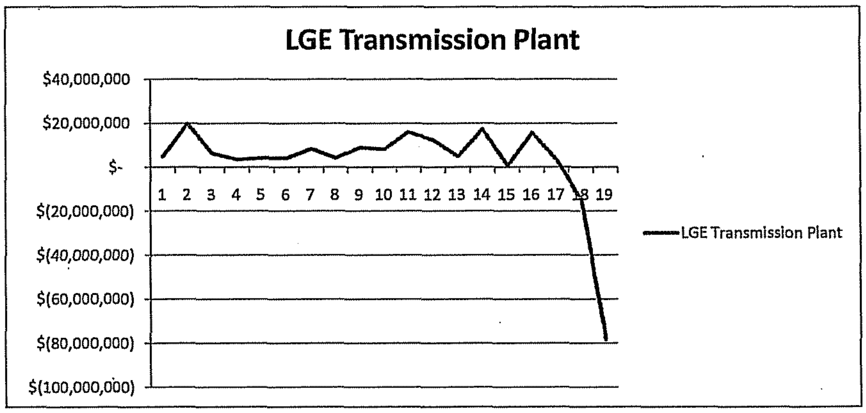
	Coal	Gas	Hydro	Total
Non Fuel	$ 46,325,467			$ 46,325,467
Fuel	$ 848,667,260	$ 59,366,214		$ 908,033,474
Total Cost	$ 894,992,727	$ 59,366,214		$ 954,358,941
Gen	35,635,560,000	705,618,000	253,802,000	36,594,980,000
$/MWh	$ 25.12	$ 84.13	$ -	**$ 26.08**

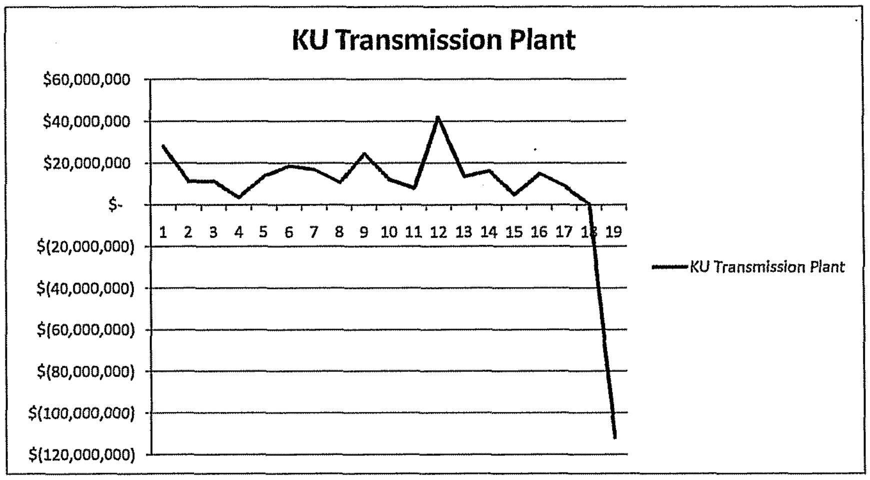
	LG&E Transmission Plant				
	Δc	Index Factor	ΔC	Δq (MW)	ΔC/Δq ($/MW)
1992-1993	$ 2,502,618	1.96	$ 4,904,342	-831	$ (5,902)
1993-1994	10,430,423	1.89	19,748,032	843	23,426
1994-1995	3,525,333	1.81	6,367,241	278	22,904
1995-1996	2,077,112	1.72	3,580,896	689	5,197
1996-1997	2,484,298	1.70	4,214,636	862	4,889
1997-1998	2,555,243	1.66	4,254,299	-205	(20,753)
1998-1999	5,104,923	1.62	8,289,476	737	11,248
1999-2000	2,561,086	1.64	4,210,727	92	45,769
2000-2001	5,691,294	1.57	8,924,077	581	15,360
2001-2002	5,423,958	1.51	8,200,115	-2	(4,100,058)
2002-2003	10,653,371	1.50	15,955,082	1749	9,122
2003-2004	8,373,198	1.49	12,473,332	-1743	(7,156)
2004-2005	3,587,061	1.37	4,929,729	457	10,787
2005-2006	13,566,451	1.27	17,294,518	1601	10,802
2006-2007	628,196	1.17	734,648	-69	(10,647)
2007-2008	14,477,762	1.08	15,586,074	1012	15,401
2008-2009	3,114,846	0.99	3,095,465	-1261	(2,455)
2009-2010	(14,692,544)	1.02	(14,946,555)	-1121	13,333
2010-2011	(78,653,033)	1.00	(78,653,033)	1629	(48,283)
Average	$ 179,558		$ 2,587,531	279	$ 9,280

Coincidence Factor	70.48%			396	$ 6,540

	KU Transmission Plant				
	Δc	Index Factor	ΔC	Δq (MW)	ΔC/Δq ($/MW)
1992-1993	$ 14,300,089	1.96	$ 28,023,663	-221	$ (126,804)
1993-1994	5,897,637	1.89	11,166,060	1581	7,063
1994-1995	6,316,884	1.81	11,409,170	799	14,279
1995-1996	11,888,561	1.72	3,580,896	1287	2,782
1996-1997	8,078,988	1.70	13,706,083	1740	7,877
1997-1998	11,197,661	1.66	18,643,313	60	310,722
1998-1999	10,373,914	1.62	16,845,368	1061	15,877
1999-2000	6,477,271	1.64	10,649,396	1101	9,672
2000-2001	15,603,236	1.57	24,466,224	1799	13,600
2001-2002	7,949,408	1.51	12,018,172	-1008	(11,923)
2002-2003	5,335,747	1.50	7,991,112	3083	2,592
2003-2004	28,277,474	1.49	42,124,205	-2117	(19,898)
2004-2005	9,891,977	1.37	13,594,629	1320	10,299
2005-2006	12,637,263	1.27	16,109,989	2747	5,865
2006-2007	4,075,797	1.17	4,766,466	-61	(78,139)
2007-2008	13,775,133	1.08	14,829,657	2069	7,168
2008-2009	8,843,391	0.99	8,788,365	-1096	(8,019)
2009-2010	98,028	1.02	99,723	-880	(113)
2010-2011	(111,673,091)	1.00	(111,673,091)	1914	(58,345)
Average	$ 3,649,756		$ 7,744,179	799	$ 9,694

Coincidence Factor	67.89%			1177	$ 6,581


LGE Transmission Plant
$40,000,000
$20,000,000
$-
$(20,000,000)
$(40,000,000)
$(60,000,000)
$(80,000,000)
$(100,000,000)
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19
LGE Transmission Plant


KU Transmission Plant
$60,000,000
$40,000,000
$20,000,000
$-
$(20,000,000)
$(40,000,000)
$(60,000,000)
$(80,000,000)
$(100,000,000)
$(120,000,000)
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19
KU Transmission Plant

Kentucky Utilities Transmission Cost
Economic Carrying Charge of Transmission Capacity Addition

Assumptions	Values
Inflation Rate (g)	2.50%
Weighted Cost of Capital (r)	7.41%
Year Scheduled to be Installed	2011
Year Installed After Load Addition	2011
a	0
Current Year	2011
m	0
PVRR	11.80
Service Life (L)	40
Economic Carrying Charge Rate (ECRR)	5.40%
Coincidence Factor	67.89%

Monthly Value (CP) =	$ **0.64**
Monthly Value (NCP) =	$ **0.43**

$$ECCR = \frac{(1+g)^m}{(1+r)^m}\left[\left(1-\frac{(1+g)^a}{(1+r)^a}\right)\left[\frac{1}{1-\frac{(1+g)^L}{(1+r)^L}}\right]\right]$$

Kentucky Utilities
Present Value Revenue Requirement Analysis
Transmission Addition

Assumptions:

Investment	$	9.694
Book Life		40
Tax Life		20
Composite Tax Rate		38.9000%
Property Tax Rate		0.55%
Levelized Revenue Requirement Years		40

Results:

Present Value Revenue Requirement	$	12
Levelized Revenue Requirement	$	1
Levelized Carrying Charge Rate		9.57%

Year	*Investment*	Book *Depreciation*	Net Plant	Tax Depreciation	Residual Plant	Deferred Income Tax	*Accumulated* Deferred Income Tax
0	$ 10						
1		$ 0	$ 9	$ 0	$ 9	$ 0	$ 0
2		0	9	1	9	0	0
3		0	9	1	8	0	0
4		0	9	1	7	0	1
5		0	8	1	7	0	1
6		0	8	1	6	0	1
7		0	8	0	6	0	1
8		0	8	0	5	0	1
9		0	8	0	5	0	1
10		0	7	0	5	0	1
11		0	7	0	4	0	1
12		0	7	0	4	0	1
13		0	7	0	3	0	1
14		0	6	0	3	0	1
15		0	6	0	2	0	1
16		0	6	0	2	0	2
17		0	6	0	2	0	2
18		0	5	0	1	0	2
19		0	5	0	1	0	2
20		0	5	0	0	0	2
21		0	5	0	0	(0)	2
22		0	4	-	0	(0)	2
23		0	4	-	0	(0)	2
24		0	4	-	0	(0)	2
25		0	4	-	0	(0)	1
26		0	3	-	0	(0)	1
27		0	3	-	0	(0)	1
28		0	3	-	0	(0)	1
29		0	3	-	0	(0)	1
30		0	2	-	0	(0)	1
31		0	2	-	0	(0)	1
32		0	2	-	0	(0)	1
33		0	2	-	0	(0)	1
34		0	1	-	0	(0)	1
35		0	1	-	0	(0)	0
36		0	1	-	0	(0)	0
37		0	1	-	0	(0)	0
38		0	0	-	0	(0)	0
39		0	0	-	0	(0)	0
40		0	(0)	-	0	(0)	0

Kentucky Utilities
Present Value Revenue Requirement Analysis
Transmission Addition

Assumptions:

Investment	$	10
Book Life		40
Tax Life		20
Composite Tax Rate		38.9000%
Property Tax Rate		0.55%
Levelized Revenue Requirement Years		40

Results:

Present Value Revenue Requirement	$	12
Levelized Revenue Requirement	$	1
Levelized Carrying Charge Rate		9.57%

Year	Rate Base	Interest	Equity	Property Taxes	Income Taxes	Annual Rev Requirement	Present Value Interest Factor	Present Value Revenue Requirement
0							1.000000	$ -
1	$ 9	$ 0	$ 1	$ 0	$ 0	$ 1	0.931012	1
2	9	0	1	0	0	1	0.866783	1
3	9	0	0	0	0	1	0.806986	1
4	8	0	0	0	0	1	0.751313	1
5	8	0	0	0	0	1	0.699482	1
6	7	0	0	0	0	1	0.651226	1
7	7	0	0	0	0	1	0.606299	1
8	7	0	0	0	0	1	0.564472	1
9	7	0	0	0	0	1	0.525530	1
10	6	0	0	0	0	1	0.489275	0
11	6	0	0	0	0	1	0.455521	0
12	6	0	0	0	0	1	0.424095	0
13	5	0	0	0	0	1	0.394838	0
14	5	0	0	0	0	1	0.367599	0
15	5	0	0	0	0	1	0.342239	0
16	4	0	0	0	0	1	0.318628	0
17	4	0	0	0	0	1	0.296647	0
18	4	0	0	0	0	1	0.276182	0
19	3	0	0	0	0	1	0.257129	0
20	3	0	0	0	0	1	0.239390	0
21	3	0	0	0	0	1	0.222875	0
22	3	0	0	0	0	1	0.207499	0
23	3	0	0	0	0	1	0.193184	0
24	2	0	0	0	0	1	0.179857	0
25	2	0	0	0	0	1	0.167449	0
26	2	0	0	0	0	0	0.155897	0
27	2	0	0	0	0	0	0.145142	0
28	2	0	0	0	0	0	0.135129	0
29	2	0	0	0	0	0	0.125807	0
30	1	0	0	0	0	0	0.117127	0
31	2	0	0	0	0	0	0.109047	0
32	2	0	0	0	0	0	0.101524	0
33	2	0	0	0	0	0	0.094520	0
34	1	0	0	0	0	0	0.087999	0
35	1	0	0	0	0	0	0.081928	0
36	1	0	0	0	0	0	0.076276	0
37	1	0	0	0	0	0	0.071014	0
38	0	0	0	0	0	0	0.066115	0
39	0	0	0	0	0	0	0.061554	0
40	(0)	(0)	(0)	(0)	(0)	0	0.057307	0

Net Present Value Revenue Requirement $ 12

Kentucky Utilities
Present Value Revenue Requirement Analysis
Transmission Addition

Assumptions:

Investment	$ 10
Book Life	40
Tax Life	20
Composite Tax Rate	38.9000%
Property Tax Rate	0.55%
Levelized Revenue Requirement Years	40

Results:

Present Value Revenue Requirement	$ 12
Levelized Revenue Requirement	$ 1
Levelized Carrying Charge Rate	9.57%

Year	Cumulative Present Value Revenue Requirement	Annual Carrying Charge Rate
0	$ -	
1	1	13.70%
2	2	13.21%
3	3	12.74%
4	4	12.29%
5	5	11.87%
6	6	11.46%
7	6	11.07%
8	7	10.70%
9	8	10.32%
10	8	9.95%
11	8	9.58%
12	9	9.21%
13	9	8.83%
14	9	8.46%
15	10	8.09%
16	10	7.72%
17	10	7.34%
18	10	6.97%
19	11	6.60%
20	11	6.23%
21	11	5.95%
22	11	5.77%
23	11	5.59%
24	11	5.41%
25	11	5.22%
26	11	5.04%
27	11	4.86%
28	11	4.68%
29	11	4.50%
30	11	4.32%
31	12	5.10%
32	12	4.81%
33	12	4.52%
34	12	4.23%
35	12	3.94%
36	12	3.65%
37	12	3.37%
38	12	3.08%
39	12	2.79%
40	12	2.50%

Louisville Gas & Electric and Kentucky Utilities
Weighted Cost of Capital and MACRS

Capital Structure:

	Percent	Rate	Weighted COC	Tax Rate	Adjusted Rate
Debt	46.52%	3.86%	1.79%	38.90%	1.10%
Preferred Equity	0.00%	0.00%	0.00%		0.00%
Common Equity	53.48%	10.50%	5.62%		5.62%
			7.41%		6.71%

Tax Depreciation Table (MACRS)

	5		15	20
1	20.000%	10.000%	5.000%	3.750%
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3	19.200%	14.400%	8.550%	6.677%
4	11.520%	11.520%	7.700%	6.177%
5	11.520%	9.220%	6.930%	5.713%
6	0.000%	7.370%	6.230%	5.285%
7	0.000%	6.550%	5.900%	4.888%
8	0.000%	6.550%	5.900%	4.522%
9	0.000%	6.560%	5.910%	4.462%
10	0.000%	6.550%	5.900%	4.461%
11	0.000%	0.000%	5.910%	4.462%
12	0.000%	0.000%	5.900%	4.461%
13	0.000%	0.000%	5.910%	4.462%
14	0.000%	0.000%	5.900%	4.461%
15	0.000%	0.000%	5.910%	4.462%
16	0.000%	0.000%	2.950%	4.461%
17	0.000%	0.000%	0.000%	4.462%
18	0.000%	0.000%	0.000%	4.461%
19	0.000%	0.000%	0.000%	4.462%
20	0.000%	0.000%	0.000%	4.461%
21	0.000%	0.000%	0.000%	2.231%
22	0.000%	0.000%	0.000%	0.000%
23	0.000%	0.000%	0.000%	0.000%
24	0.000%	0.000%	0.000%	0.000%
25	0.000%	0.000%	0.000%	0.000%
26	0.000%	0.000%	0.000%	0.000%
27	0.000%	0.000%	0.000%	0.000%
28	0.000%	0.000%	0.000%	0.000%
29	0.000%	0.000%	0.000%	0.000%
30	0.000%	0.000%	0.000%	0.000%

Louisville Gas & Electric Transmission Cost
Economic Carrying Charge of Transmission Capacity Addition

Assumptions	**Values**
Inflation Rate (g)	2.50%
Weighted Cost of Capital (r)	7.41%
Year Scheduled to be Installed	2011
Year Installed After Load Addition	2011
a	0
Current Year	2011
m	0
PVRR	11.30
Service Life (L)	40
Economic Carrying Charge Rate (ECRR)	5.40%
Coincidence Factor	70.48%

Monthly Value (CP) =	$ **0.61**

Monthly Value (NCP) =	$ **0.43**

$$ECCR = \frac{(1+g)^m}{(1+r)^m}\left[\left(1-\frac{(1+g)^a}{(1+r)^a}\right)\left[\frac{1}{1-\frac{(1+g)^L}{(1+r)^L}}\right]\right]$$

Louisville Gas & Electric
Present Value Revenue Requirement Analysis
Transmission Addition

Assumptions:

Investment	$ 9.280
Book Life	40
Tax Life	20
Composite Tax Rate	38.9000%
Property Tax Rate	0.55%
Levelized Revenue Requirement Years	40

Results:

Present Value Revenue Requirement	$ 11
Levelized Revenue Requirement	$ 1
Levelized Carrying Charge Rate	9.57%

Year	Investment	Book Depreciation	Net Plant	Tax Depreciation	Residual Plant	Deferred Income Tax	Accumulated Deferred Income Tax
0	$ 9						
1		$ 0	$ 9	$ 0	$ 9	$ 0	$ 0
2		0	9	1	8	0	0
3		0	9	1	8	0	0
4		0	8	1	7	0	0
5		0	8	1	7	0	1
6		0	8	0	6	0	1
7		0	8	0	6	0	1
8		0	7	0	5	0	1
9		0	7	0	5	0	1
10		0	7	0	4	0	1
11		0	7	0	4	0	1
12		0	6	0	4	0	1
13		0	6	0	3	0	1
14		0	6	0	3	0	1
15		0	6	0	2	0	1
16		0	6	0	2	0	1
17		0	5	0	1	0	2
18		0	5	0	1	0	2
19		0	5	0	1	0	2
20		0	5	0	0	0	2
21		0	4	0	(0)	(0)	2
22		0	4	-	(0)	(0)	2
23		0	4	-	(0)	(0)	2
24		0	4	-	(0)	(0)	1
25		0	3	-	(0)	(0)	1
26		0	3	-	(0)	(0)	1
27		0	3	-	(0)	(0)	1
28		0	3	-	(0)	(0)	1
29		0	3	-	(0)	(0)	1
30		0	2	-	(0)	(0)	1
31		0	2	-	(0)	(0)	1
32		0	2	-	(0)	(0)	1
33		0	2	-	(0)	(0)	1
34		0	1	-	(0)	(0)	1
35		0	1	-	(0)	(0)	0
36		0	1	-	(0)	(0)	0
37		0	1	-	(0)	(0)	0
38		0	0	-	(0)	(0)	0
39		0	0	-	(0)	(0)	0
40		0	(0)	-	(0)	(0)	0

Louisville Gas & Electric
Present Value Revenue Requirement Analysis
Transmission Addition

Assumptions:

Investment	$	9
Book Life		40
Tax Life		20
Composite Tax Rate		38.9000%
Property Tax Rate		0.55%
Levelized Revenue Requirement Years		40

Results:

Present Value Revenue Requirement	$	11
Levelized Revenue Requirement	$	1
Levelized Carrying Charge Rate		9.57%

Year	Rate Base	Interest	Equity	Property Taxes	Income Taxes	Annual Rev Requirement	Present Value Interest Factor	Present Value Revenue Requirement
0							1.000000	$ -
1	$ 9	$ 0	$ 1	$ 0	$ 0	$ 1	0.931012	1
2	9	0	0	0	0	1	0.866783	1
3	8	0	0	0	0	1	0.806986	1
4	8	0	0	0	0	1	0.751313	1
5	8	0	0	0	0	1	0.699482	1
6	7	0	0	0	0	1	0.651226	1
7	7	0	0	0	0	1	0.606299	1
8	7	0	0	0	0	1	0.564472	1
9	6	0	0	0	0	1	0.525530	1
10	6	0	0	0	0	1	0.489275	0
11	6	0	0	0	0	1	0.455521	0
12	5	0	0	0	0	1	0.424095	0
13	5	0	0	0	0	1	0.394838	0
14	5	0	0	0	0	1	0.367599	0
15	4	0	0	0	0	1	0.342239	0
16	4	0	0	0	0	1	0.318628	0
17	4	0	0	0	0	1	0.296647	0
18	4	0	0	0	0	1	0.276182	0
19	3	0	0	0	0	1	0.257129	0
20	3	0	0	0	0	1	0.239390	0
21	3	0	0	0	0	1	0.222875	0
22	3	0	0	0	0	1	0.207499	0
23	2	0	0	0	0	1	0.193184	0
24	2	0	0	0	0	1	0.179857	0
25	2	0	0	0	0	0	0.167449	0
26	2	0	0	0	0	0	0.155897	0
27	2	0	0	0	0	0	0.145142	0
28	2	0	0	0	0	0	0.135129	0
29	2	0	0	0	0	0	0.125807	0
30	1	0	0	0	0	0	0.117127	0
31	2	0	0	0	0	0	0.109047	0
32	2	0	0	0	0	0	0.101524	0
33	2	0	0	0	0	0	0.094520	0
34	1	0	0	0	0	0	0.087999	0
35	1	0	0	0	0	0	0.081928	0
36	1	0	0	0	0	0	0.076276	0
37	1	0	0	0	0	0	0.071014	0
38	0	0	0	0	0	0	0.066115	0
39	0	0	0	0	0	0	0.061554	0
40	(0)	(0)	(0)	(0)	(0)	0	0.057307	0
Net Present Value Revenue Requirement								$ 11

Louisville Gas & Electric
Present Value Revenue Requirement Analysis
Transmission Addition

Assumptions:

Investment	$	9
Book Life		40
Tax Life		20
Composite Tax Rate		38.9000%
Property Tax Rate		0.55%
Levelized Revenue Requirement Years		40

Results:

Present Value Revenue Requirement	$	11
Levelized Revenue Requirement	$	1
Levelized Carrying Charge Rate		9.57%

Year	Cumulative Present Value Revenue Requirement	Annual Carrying Charge Rate
0	$ -	
1	1	13.70%
2	2	13.21%
3	3	12.74%
4	4	12.29%
5	5	11.87%
6	6	11.46%
7	6	11.07%
8	7	10.70%
9	7	10.32%
10	8	9.95%
11	8	9.58%
12	8	9.21%
13	9	8.83%
14	9	8.46%
15	9	8.09%
16	10	7.72%
17	10	7.34%
18	10	6.97%
19	10	6.60%
20	10	6.23%
21	10	5.95%
22	10	5.77%
23	11	5.59%
24	11	5.41%
25	11	5.22%
26	11	5.04%
27	11	4.86%
28	11	4.68%
29	11	4.50%
30	11	4.32%
31	11	5.10%
32	11	4.81%
33	11	4.52%
34	11	4.23%
35	11	3.94%
36	11	3.65%
37	11	3.37%
38	11	3.08%
39	11	2.79%
40	11	2.50%

Louisville Gas & Electric and Kentucky Utilities
Weighted Cost of Capital and MACRS

Capital Structure:

	Percent	Rate	Weighted COC	Tax Rate	Adjusted Rate
Debt	46.52%	3.86%	1.79%	38.90%	1.10%
Preferred Equity	0.00%	0.00%	0.00%		0.00%
Common Equity	53.48%	10.50%	5.62%		5.62%
			7.41%		6.71%

Tax Depreciation Table (MACRS)

	5		15	20
1	20.000%	10.000%	5.000%	3.750%
2	32.000%	18.000%	9.500%	7.219%
3	19.200%	14.400%	8.550%	6.677%
4	11.520%	11.520%	7.700%	6.177%
5	11.520%	9.220%	6.930%	5.713%
6	0.000%	7.370%	6.230%	5.285%
7	0.000%	6.550%	5.900%	4.888%
8	0.000%	6.550%	5.900%	4.522%
9	0.000%	6.560%	5.910%	4.462%
10	0.000%	6.550%	5.900%	4.461%
11	0.000%	0.000%	5.910%	4.462%
12	0.000%	0.000%	5.900%	4.461%
13	0.000%	0.000%	5.910%	4.462%
14	0.000%	0.000%	5.900%	4.461%
15	0.000%	0.000%	5.910%	4.462%
16	0.000%	0.000%	2.950%	4.461%
17	0.000%	0.000%	0.000%	4.462%
18	0.000%	0.000%	0.000%	4.461%
19	0.000%	0.000%	0.000%	4.462%
20	0.000%	0.000%	0.000%	4.461%
21	0.000%	0.000%	0.000%	2.231%
22	0.000%	0.000%	0.000%	0.000%
23	0.000%	0.000%	0.000%	0.000%
24	0.000%	0.000%	0.000%	0.000%
25	0.000%	0.000%	0.000%	0.000%
26	0.000%	0.000%	0.000%	0.000%
27	0.000%	0.000%	0.000%	0.000%
28	0.000%	0.000%	0.000%	0.000%
29	0.000%	0.000%	0.000%	0.000%
30	0.000%	0.000%	0.000%	0.000%